
CHAPTER 5 FOSSIL FUEL ANALYSIS

5.1 Background

5.1.1 Natural Gas

The natural gas system in Armenia was originally designed as a part of a regional Caucasus system that was integrated into the energy system of the former USSR. Originally constructed in the 1960s, a 700 mm line entered Armenia from Azerbaijan. Another 1000 mm line (similar route) was completed in 1990s. In 1993, in order to deal with the Azeri energy embargo, a 1000 mm direct line was installed between Georgia and Armenia [1].

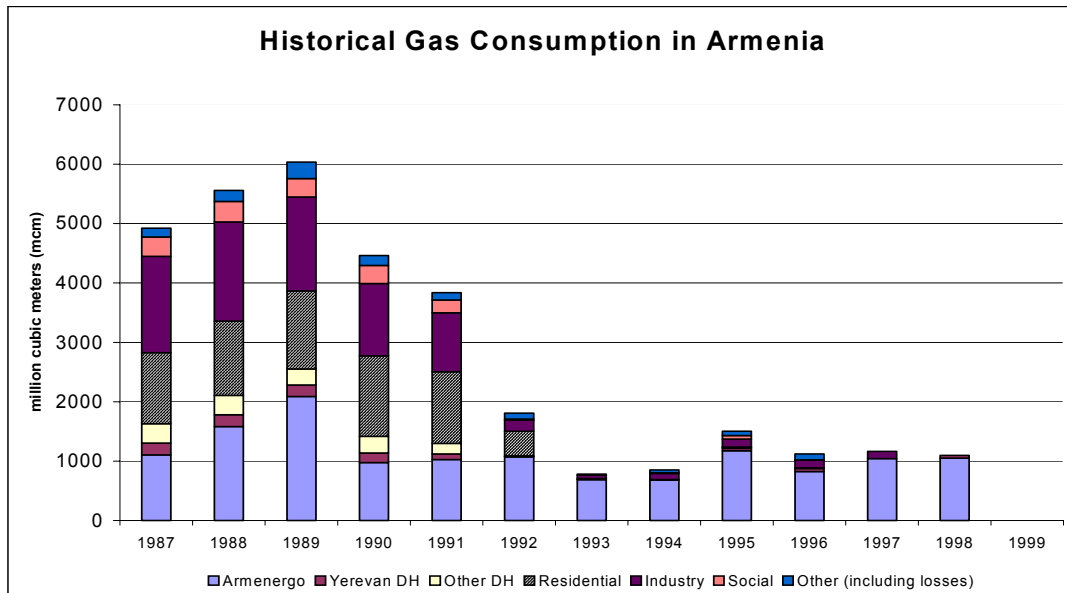
Other pipelines connect Armenia with Turkmenistan, Kazakhstan, Uzbekistan, and Iran, but go through Azerbaijan territory and are therefore subject to the Azeri energy embargo. Technically speaking, gas from other countries could still be delivered through the North-Caucasus Trans-Caucasus pipeline system with proper rehabilitation of pipelines currently not in operation.

Until 1972, most of the gas imported to Armenia came from Sarajeh gas field in Iran via the Kazakh-Yerevan pipeline (through Azerbaijan). This 700 mm pipeline was constructed in the 1960s and was later expanded with the addition of a 1000 mm pipeline. The northern part of Armenia was served with another 500 mm pipeline. During the 1970s, due to increasing tensions between Iran and the USSR, imports from Iran were decreased and substituted with imports from Siberia and Turkmenistan.

Historically, Armenia had very high levels of natural gas consumption. Natural gas consumption increased throughout the 1980s, reaching a peak of 6.3 billion cubic meters (bcm) in 1989. At that time, the power generation sector consumed about 33% of the total gas supplying the country. However, since 1989 the escalation of the Nagorno-Karabakh conflict has resulted in numerous supply interruptions and an overall decrease in consumption.

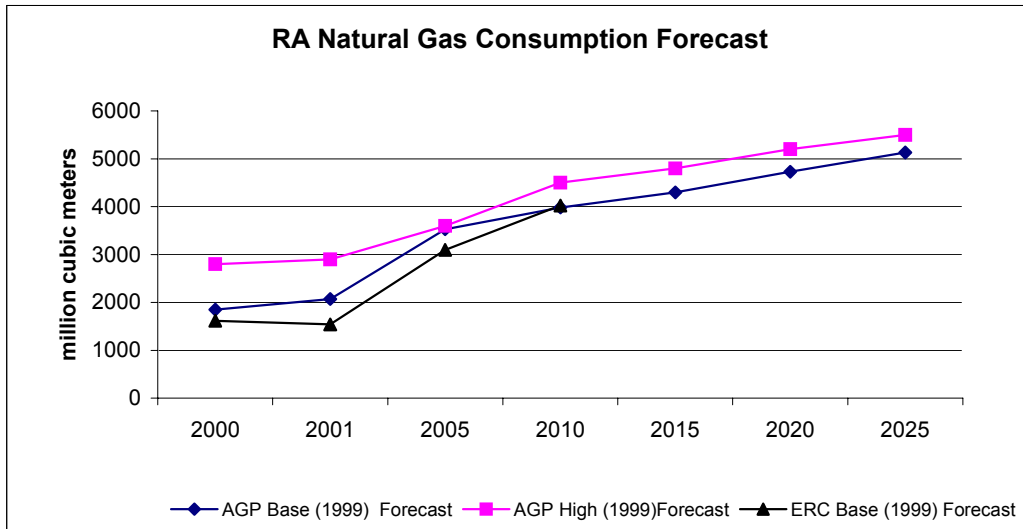
Overall amounts of gas consumption significantly decreased in 1991-93. At the same time, the amount of gas used for power generation remained relatively stable during that period. Most of the decline took place in industrial and residential consumption. Historical natural gas consumption is shown in Exhibit 1 below:

Exhibit 1



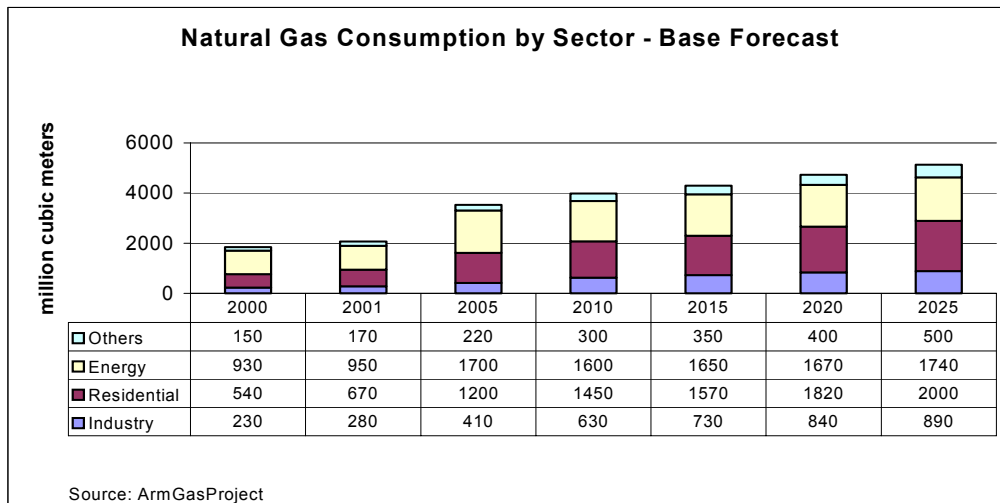
There is no consensus on the future consumption pattern for natural gas for the country. Historically, gas consumption was relatively stable in the energy sector. The higher utilization of the nuclear unit (at least up to year 2004) and the possibilities of using other alternative fuels (as discussed in sections below) will bring energy sector consumption to lower levels. At the same time, a re-gasification program (currently in progress) for the residential sector should be able to compensate for energy sector consumption decreases. There are several forecasts for gas consumption that are currently available and can be treated as a reference. Most of these forecasts are somewhat outdated and assume higher economic growth than the country currently experiences. Exhibit 2 presents the 2000-2025 official forecasts (base and high) prepared by ArmGasProject (AGP) in 1999 and the unofficial 2000-2010 base forecast [3] prepared by the Energy Regulatory Commission (ERC).

Exhibit 2



A sector breakdown for the AGP base case forecast is presented in Exhibit 3.

Exhibit 3

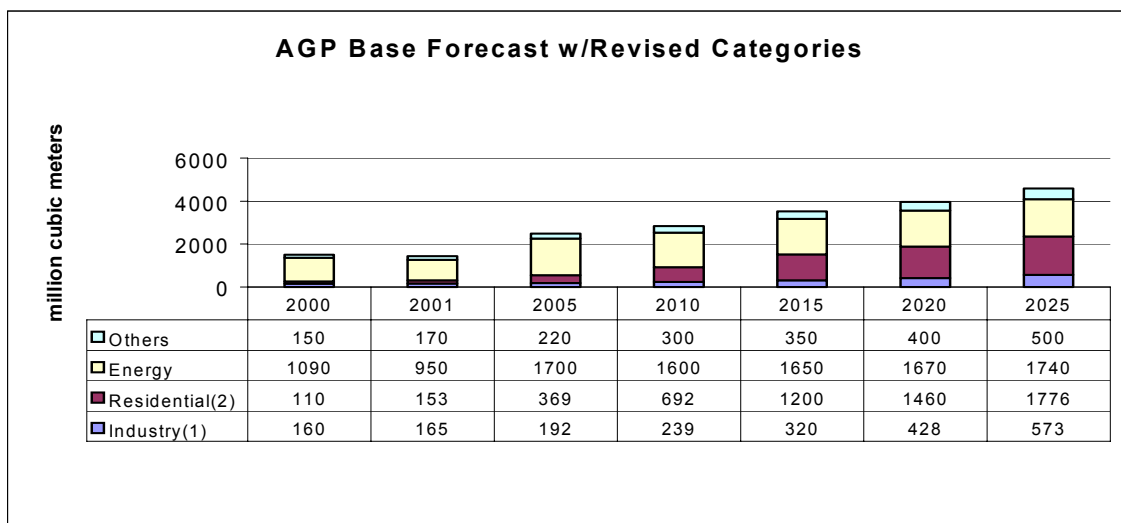


There is a significant increase in the energy sector consumption starting in year 2005. This forecast accounts for the phasing out of ANPP in 2004 and the substitution of its capacity with a gas-fired unit(s).

According to a series of discussions with gas supply and transport people as well as other domestic and international organizations, the re-gasification process is in a stagnation phase now. This is primarily due to the lack of available finances for gas system

rehabilitation and metering installations. Several international organizations, including UNDP and GEF are providing limited technical assistance in this area. The current consensus among Government officials is that the re-gasification goal of reaching year 1991 residential consumption levels (about 1,207 million cubic meters) can be achieved not earlier than year 2010 (ERC unofficial estimate projects even longer period), whereas the original plan targeted 2001 completion. This statement is a probable cause for correcting the AGP Base Forecast using more up-to-date data developed by the ERC (unofficial publication [3]) as shown on Exhibit 4.

Exhibit 4



(1) Revised as per unofficial ERC estimate up to year 2010. 6% growth/year assumed thereafter.

(2) Revised as per unofficial ERC estimate up to year 2010. 1991 level reached by 2015. 4% growth/year assumed thereafter.

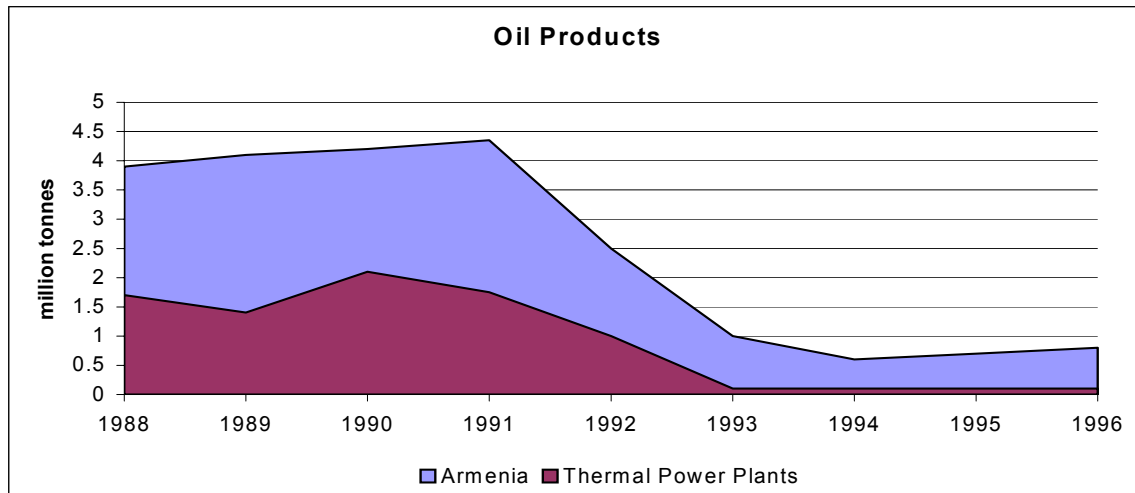
5.1.2 Mazut

Armenia has no significant domestic petroleum reserves, so most petroleum products (including mazut) are imported. However, unlike natural gas, there are no oil pipelines in Armenia [1]. Most supplies of oil are delivered to Armenia by rail and trucks.

Historically, Armenia received most of its petroleum products from refineries in Azerbaijan (Baku) and Russia (Grozny). However, in the period since Armenia declared independence, the situation has drastically changed. The Azeri embargo ended all oil imports from Baku and petroleum and mazut supplies fell sharply after 1993. Exhibit 5 presents the consumption of oil products (including mazout for power plants) for the 1988-1996 period.

Currently, most of the mazut in Armenia comes from Russian refineries and is shipped from Novorossiysk. Some amount of mazut is delivered from Batumi, Georgia.

Exhibit 5



HB Fuel Supply Report, 1999 update

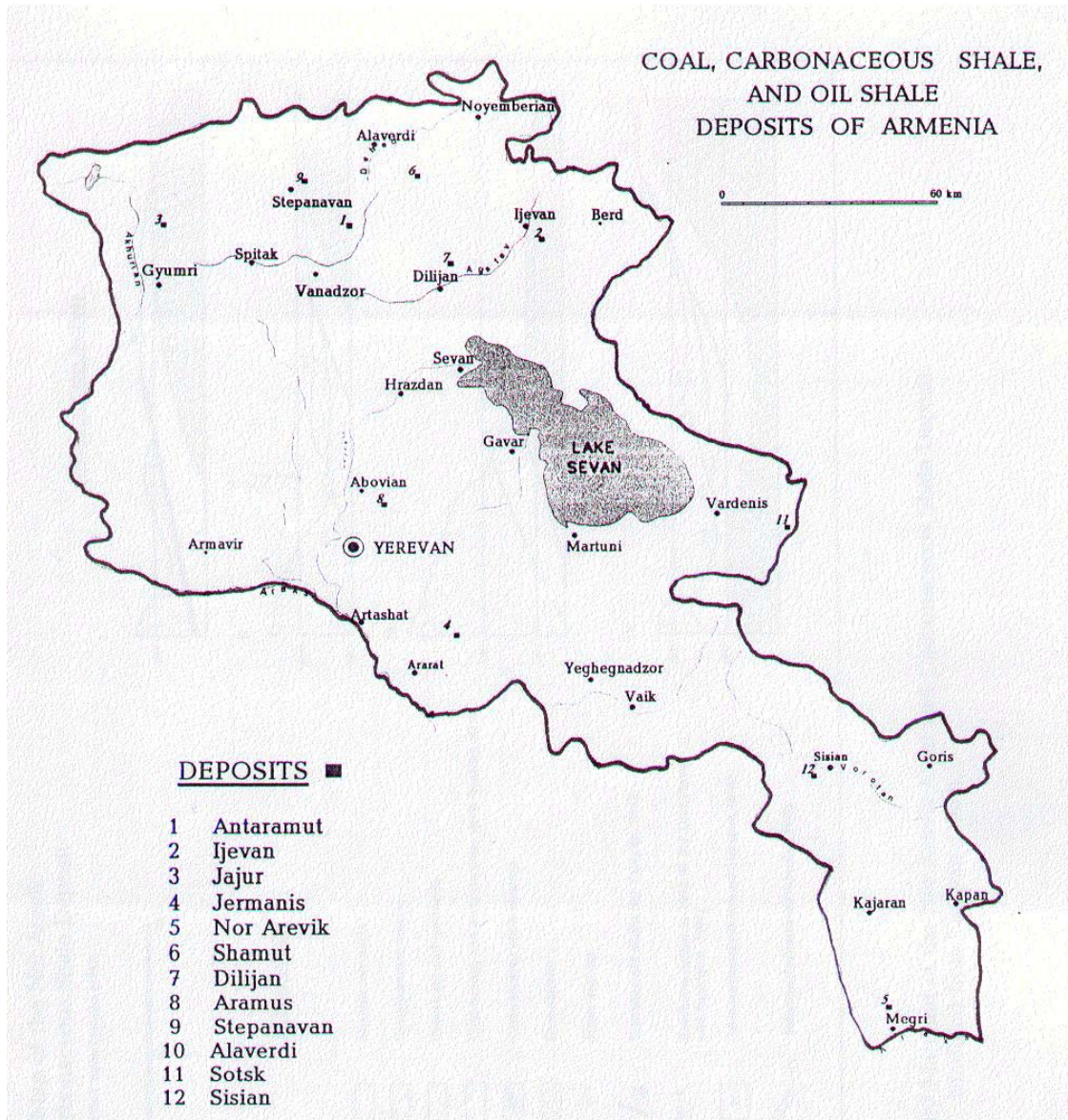
Currently, mazut is practically absent in the energy sector. Some amount of mazut reserve is stored on the TPP sites. Full storage capacity at TPPs is about 350,000 tonnes of mazut.

5.1.3 Coal¹

A coal reserve evaluation was performed for power generation purposes only. No domestic (household) use is taken into account. The evaluation is based on the 50 MW (or larger) circulating fluidized bed (CFB) unit installation.

There are six known coal fields in Armenia – Nor Arevik, Antaramut, Shamut, Idjevan, Jermanis, and Jajur, as well as other minor coal deposits. Armenia also contains oil shale deposits at Dilijan, Aramus, Jajur, and Nor Arevik [4]. Currently, no major development work is taking place for the utilization of Armenian coal/shale resources for energy production. Exhibit 6 shows the map of major coal/shale deposits in Armenia.

¹ Metric tonnes are used for measurement, unless otherwise mentioned.

Exhibit 6

Source: USGS, [4]

The U.S. Geological Survey (USGS), under contract to the USAID, conducted the Armenian Coal Exploration and Resource Assessment Program during 1997-99. As a part of this program, several activities related to energy sector needs were initiated: (a) exploratory drilling and (b) research works into the major coal fields of Armenia, (c) detailed coal exploration and the economic assessment of the Antaramut-Kurtan-Dzoragukh coal field. This program is probably the most comprehensive assessment of Armenia's coal resources available today. The program included the research on the existing coal data as well as verification and analysis of the new

data received during exploratory drilling. Computer re-calculation techniques were used to calculate the potential coal reserves.

As per USGS, Armenian coal resources can be classified as follows:

	Category Types			
USGS Classification	Measured	Indicated	Inferred	Hypothetical
USSR (GOST) Classification	A and B	C1	C2	H1 and H2

Both systems classify coal resources and reserves based upon the degree of geologic control and the economic feasibility of recovery. Each category is dependent upon the density of the exploration network.

Since most of the USGS's work was focused on coal deposits, no accurate estimates are available on oil shale reserves. Oil shale can also be used for large scale power generation if the reserve quantities are proven to be sufficient. Exhibit 7 provides estimates of the coal/shale reserves.

Exhibit 7 – Coal/Shale Reserves

			Resources Estimates (in metric tonnes)			
	Potential Local Fuel Deposits	Type of Fuel	Official Government (all categories)	USGS Total Recalculated	USGS Best Reference (if not recalculated)	Average Calorific Value (kcal/kg - dry)
1	<i>Shamut</i>	Coal	8,623,000	14,646,822	N/A	2,370-5,950
2	<i>Jajur</i>	Coal	355,200	483,538	N/A	3,940-5,245
3	<i>Ijevan</i>	Coal	97,780,000	97,780,000	N/A	4,000-6,000
4	<i>Nor Arevik</i>	Coal	22,500	Not performed	22,285	3,000-7,000
		Combust. Shale	355,600	Not performed	498,847	<2000
5	<i>Jermanis</i>	Coal	2,251,000		393,414	N/A
6	<i>Antaramut</i>	Coal		168,948	Note 1	8,142-8,599

Note 1. Since recalculation was done for a limited area, USGS estimates **31,597,040** MT of coal for whole Antaramut deposit

References available today show (sum of bold figures) the potential for up to 147 million tonnes of coal resources (all classified categories) to qualify as coal which could possibly provide for economic coal reserves to support coal-fired power generation.

However, for all practical evaluations, only *measured* (A and B) and *indicated* (C1) categories should be evaluated. The identified coal resources in these classifications are estimated at only about 6 million tonnes. This reserve estimate includes only Antaramut, Shamut, and Jajur coal deposits, since no measured or indicated resources are proven for other deposits. The following paragraphs provide the description and rationale of the exploration of Antaramut and Shamut deposits.

(a) Antaramut Deposit

A pre-feasibility study conducted by the USGS has been completed for the 1.4 million tonne coal reserve. This pre-feasibility study provides a cost estimate for developing this particular coal deposit in Armenia, which in turn can be used as a basis for cost estimation of other coal deposits which could employ a contour haulback mining method complemented by an auger mining method. This study concludes that the recoverable economic coal reserve is approximately 916,000 tonnes.

The coal resources provided by USGS indicate 4.1 million tonnes of C1 and 26.0 million tonnes of C2 class coal within the Antaramut coal resource. The coal dips away from the ground surface in the north at about 15° to the south while topography and layers of earth, or overburden, overlying the coal increase towards the south. This combination of decreasing coal elevation along the dip coupled with the increasing elevation of the ground surface overlying the coal creates a coal resource which has very limited potential for economic surface mining. Given the structural environment within which this coal exists, most of the Antaramut coal resource would have to be mined using underground mining techniques. Underground mining techniques at Antaramut are not expected to be economically feasible because the seams are too thin and inconsistent for efficient underground mining.

The portion of the coal reserve that outcrops at the surface has been included in the pre-feasibility study conducted by the USGS. The potential for economically mineable reserves for the Antaramut coal deposit have been summarized by this report and can be assumed to be about 900,000 tonnes. It should be mentioned that there is a small section of coal in the southeastern portion of this deposit which does outcrop, possibly providing some additional coal reserve potential, although it is expected to contribute a small quantity, if any.

In summary, we conclude that the potential for economically mineable reserves at the Antaramut deposit can be assumed to be about 900,000 tonnes of coal which could be sold on the market. There are other coal resource in this deposit but it is unlikely this coal could be economic because the coal layer is too thin for economic underground mining and has limited surface mining potential.

(b) Shamut Deposit

The resource estimate for Shamut projects a maximum of 14.7 million tonnes for the current strike length assumption of 4 kilometers. This estimate includes all sections that contain coal, and therefore, includes sections of non-mineable layers. With an average calorific value of 2,100 kcal/kg, a 50 MW power station would require approximately 600,000 tonnes of carbonaceous shale per year. Over a 35-year life, the total mineable reserve required would be 21 million tonnes.

USGS, though, is of the opinion that this resource has a greater strike length than that assumed by prior Armenian studies; it believes that a strike length of 8 kilometers could be possible. If this is the case, then it is possible that the total reserve could increase to 28 million tonnes of

resource. It is impossible at this point to determine if the necessary 21 million tonnes of carbonaceous shale is recoverable from the Shamut coal resource area.

Our analysis has shown that much of the reserve could very well be lost because carbonaceous layers are too thin for mining and because combining layers into mineable sections would develop a product with very high ash. In addition, a more selective mining process would adversely affect the mining economics and reduce the reserve volume. A review of the information available on the reserve suggests that a significant portion of this deposit may not be recoverable and that it would be a very low quality product because of too much ash.

We conclude that the Shamut carbonaceous shale deposit may very well not have adequate resource to provide enough fuel for a 50 MW fluidized bed power station. In addition, the calorific value of the beds of carbonaceous coal, at 2,100 kcal/kg, is extremely low. The large quantity of ash generated by burning this fuel would require the power station be located near the Shamut site in order to reduce transportation and ash handling costs to economical levels. The remoteness of the Shamut site will require additional capital investment, such as a new 20-kilometer access road, to enable mining and haulage operations. Because of the remote location of this resource, the low heat content, and the lack of local infrastructure, other resources should be considered before the Shamut site. We recommend that the Shamut site only be considered as a carbonaceous shale deposit that would produce a product with ash in excess of 50%.

Potential

In addition to measured and indicated classifications, some attention should be paid to Ijevan deposit. This deposit has no measured or indicated reserves, but large inferred (C2) and hypothetical (P1 and P2) reserves.

The coal deposit has not been fully evaluated by the USGS, but they are of the opinion that the coal field is larger than the expectation of the Armenian geological professionals. Resources reported officially by the Armenian government are 9.8 million tonnes of C2 and 88 million tonnes of P classification. It has been determined by USGS, that this deposit is geologically complex. In the current area of mapping, dips are very steep. Coal is of Jurassic age and has a coal bearing section thickness of from 25 to 26 meters. Only one coal bed has been identified and it is about 16 to 18 meters thick. The beds dip down at a very steep angle, from 45 to 70°.

There is much faulting and complex structural conditions exist in this deposit. The visible outcrop area, where small-scale mining is taking place, displays complex faulting and is completely “sheared, squeezed, twisted and contorted, indicating a lot of tectonic deformation. The coal is sheared and broken, not really cleated” according to USGS descriptions.

Assuming the sampling done by USGS is representative of the section being sampled, there is the potential for good coal reserves because the section of the coal is rather thick. Beyond this potential, there is a fairly thick section within the seam confines that could possibly be selectively mined to produce a product with a much higher calorific value.

If this sampling is indicative of the total deposit, then two major differences will have been found in the Ijevan deposit that to date have not been found in the remainder of Armenia. These two important criteria are thickness, combined with a potential for higher quality coal. It is of interest to note that an as-received quality as high as 5,500 kcal/kg (9,900 btu/lb.) may be mineable from within the interior of the seam over a 14-meter thickness.

It may be, therefore, that a 5-meter section of significantly higher quality coal exists within the confines of the coal bed. If this is the case, then we could project over a 600-meter length and an 800-meter depth, an in-bed volume of coal equal to about 4 million tonnes, assuming a density of 1.6 g/cm³. If we assume the full bed thickness of 22 meters then we calculate that 17 million tonnes of resource may be in place. We can then project that a 50% underground mining recovery rate would reduce the recoverable reserves in this deposit down to 2 million and 8.5 million tonnes, respectively, if it is economic to recover the reserves. This reserve estimate appears to correlate to the C2 reserve estimate of 9.8 million tonnes calculated by the Armenian professionals.

If an average calorific value of 4,400 kcal/kg could be produced by mining the 22-meter thick seam, then roughly 10 million tonnes of coal would be necessary for the power station life of 35 years. ***It appears there may be adequate volume in this reserve if lateral boundaries of the resource can be expanded.*** Lateral expansion would also be of value in reducing the depths of mining projected here to obtain the reserves needed to support 50 MW of fluidized bed power station.

The reserve at Ijevan could only be mined by underground mining methods in order to develop reserves of any magnitude. It is expected that a breast-and-pillar mining method used in the anthracite coal sector in the Appalachian coal region of the eastern United States could be employed at this site. This is a labor-intensive method employing limited mechanized mining equipment because of the difficulty of using such equipment in such steeply dipping conditions. A method somewhat similar to this is employed at the Tkibuli mine in Georgia. Given that labor rates are currently low in Armenia, it may be economic to employ such a mining method. Because this method is no longer used in the U.S. it is difficult to project at this point in time whether such a venture in Armenia could be economic. It is known however that the professionals at the Tkibuli mine are of the opinion their project, which produces a similar quality coal with a similar method, is economic.

The Ijevan deposit is described as geologically complex and faulted. There is a chance the deposit has been so massively impacted by geologic events that the deposit will be very difficult to mine. Complex faulting may have destroyed the integrity of the overlying and underlying non-coal beds such that it will be impossible to economically support underground mine openings long enough to win the coal. Major fault structures could also reduce available coal reserves and disrupt mining efforts. There could also be water problems associated with the faults which could make mining more difficult and expensive. It is also not known how well the immediate

roof structure, which has been described as a tuffaceous clay, will be able to act as a roof for mining operations.

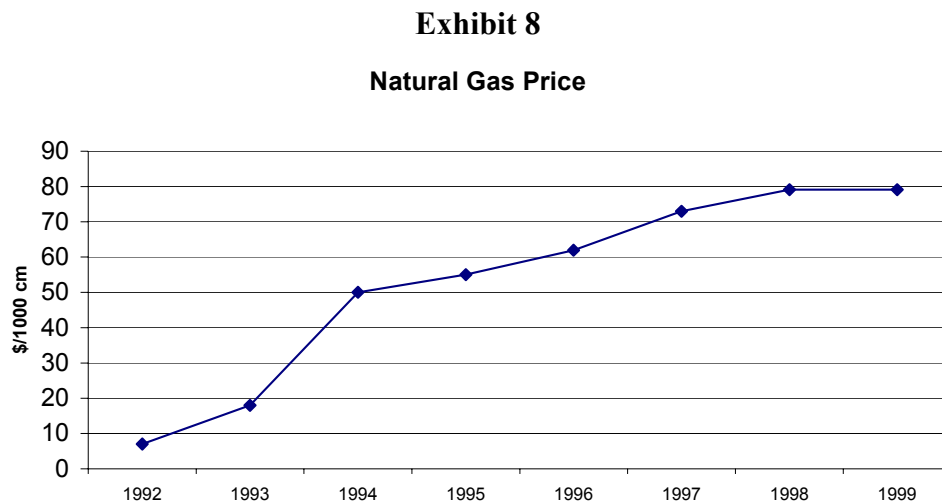
All in all, this deposit may have adequate resources to support a 50 MW coal-fired power station but additional resources need to be found beyond the current limits of the known resource. If adequate resource does exist, two major conditions may prevent the economic mining of coal from the deposit. First, a labor-intensive underground mining method will be necessary to mine the coal and Armenian experience with underground coal mining techniques is non-existent. Second, the geologic conditions with the deposit may be so complex or of a nature that mining of the deposit would be either impossible or too expensive. On a positive note, the deposit location is in an area that provides ready access to a labor force, available infrastructure, and rail access. At this point in time, inadequate information is available to properly assess the likely feasibility of the mining concept.

We recommend further exploration be conducted to gather additional information about the Ijevan deposit. This deposit is likely marginally economic, as are most deposits in Armenia, but it falls within the confines of the task that has been established for this program. The decision of whether to go forward with this project is difficult to make. There are no guidelines established upon which a reasonable decision can be made. It is necessary that more concrete parameters be established to guide this decision-making process before additional work effort is expended.

5.2 Fuel Prices

5.2.1 *Natural Gas*

Natural gas prices have significantly increased since 1992. Following Exhibit 8 presents the growth of natural gas prices for power generation.



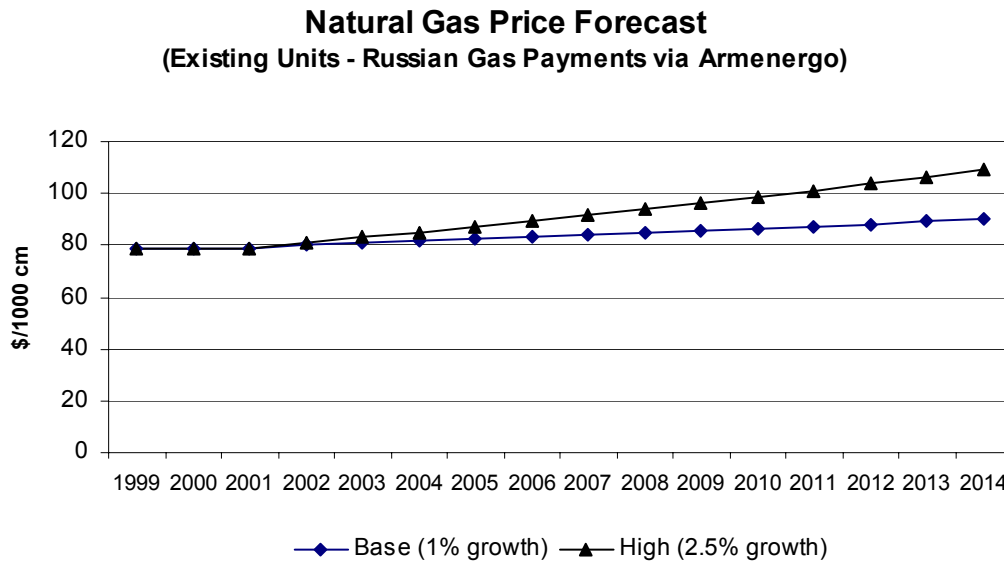
For the purpose of this analysis two natural gas annual escalations were used: Base and High. Currently, there is no consensus on the pattern of gas price escalation in Armenia. The world trend for escalation may not be directly applied to the situation in Armenia. Russian gas currently supplied to the country has more of a “political” than economic nature. Since some competition

is expected on the gas market in Armenia, a Base escalation scenario is proposed (1% annual price escalation). Various supply diversification options are discussed in Section 5.3.

OECD and IEA [2] provide annual gas escalation rates for both OECD and Non-OECD countries (including Russia). Gas escalations vary from 0.1-0.2%/year in Brazil and Hungary to 2.7-3.8%/year in Japan and the US. Current pricing of natural gas also varies significantly. The Russian gas price in year 2005 is predicted to be about \$2.68/GJ, which corresponds to growth of approximately 2.4 percent per year.

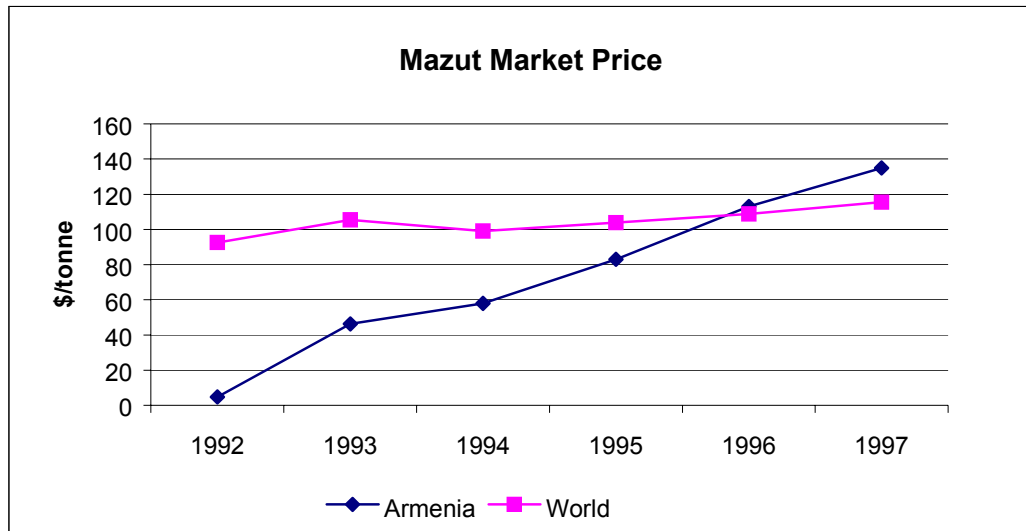
Exhibit 9 presents the proposed escalation forecast pattern for Russian gas. It should be noted that, according to ArmRosGasProm's current position, no gas price increase is expected until year 2003. Exhibit 9 reflects so-called "government" contracts only (i.e., contracts through Armenergo). Independent gas purchases for power use and purchase prices are described in Section 5.3.3.

Exhibit 9



5.2.2 Mazut

Exhibit 10 presents the escalation of mazut prices in Armenia and also shows the world trend. Currently, the country transport component is estimated at about 30% of the mazut price in Armenia. This is mainly due to the delivery mechanism by trucks and the difficulty associated with using existing railroad links.

Exhibit 10

HB Fuel Supply Report, 1999 update

5.2.3 Coal

USGS has prepared [5] a preliminary cost estimate for a coal exploration effort in the Antaramut-Kurtan-Dzoragukh coal field in North-Central Armenia. The production tariff derived in this study is based on the limited quantities of coal exploration only. However, this is the only independent estimate that was available at the time of this study.

It is estimated that the cost per annual tonne of production can be about \$15/tonne in the case of strip and augur mining and about \$20/tonne for strip mining only.

If we assume that coal would be delivered from a location such as the Antaramut area that has local rail access, then we can project the rail transportation component of the costs. The rail haulage costs per tonne-kilometer, for bulk materials, were quoted by Armenian transportation officials as equivalent to \$0.024, assuming an exchange rate of 540 dram per U.S. dollar.

The rail haulage distance from the Antaramut project to the Hrazdan power project is estimated to be about 300 kilometers. With the \$0.024 unit haulage cost assumption, we can calculate the transportation cost to Hrazdan from the Antaramut project to be \$7.20 per tonne. By assuming the free-on-board (FOB) \$18.88 per tonne cost to produce coal from the Antaramut project as a reasonable cost of coal in Armenia, we can project the Hrazdan delivered theoretical cost of coal to be \$26.08 or \$26 per tonne.

It is clear that further economic calculations must be performed to verify the coal price at other identified coal fields. For the purpose of this Plan, the Burns and Roe estimate of \$5.88/Gcal (4,400 kcal/kg) at the “burner tip” is considered appropriate. No escalation of the price is foreseen, since mass mining will most likely bring the unit price down.

Alternative (Supplemental) Coal Sources

As the domestic coal potential dwindles, an alternative (supplement) that appears reasonable is the development of a foreign coal source. One source within the region is the Georgian Tkibuli coal mine, near the city of Kutaisi in western central Georgia.

This mine appears to have at least 60 million tonnes of coal reserve that could be sold on the open market but is currently facing an extremely lackluster market due to regional economic problems. The mine is an underground facility working a rather thick section of coal on the flank of a synclinal coal deposit. The production capacity of the mine has been estimated to be between 500,000 and 1,000,000 tonnes per year but currently is selling less than 50,000 tonnes per year. The produced coal has a lower-calorific value of 4,300 kcal/kg, a sulfur content of 1.2%, and an average ash content of 34%, on an as-received basis. It is expected this coal could be sold FOB mine for a price of roughly \$30 to \$35 per tonne, including value-added tax (VAT).

The cost of delivered Tkibuli coal to the Hrazdan site can be estimated because the coal can be delivered by rail from Tkibuli to Hrazdan. The exact condition of the rail all along the route is not known but it is operable and used for the most part. It is known there are sections where the rail bed requires improvement. The rail distance from Tkibuli to the Armenian border near Sadakhlo, Georgia, is estimated at 260 kilometers, and the distance from that point to Hrazdan is estimated to be 360 kilometers. The Georgian bulk cargo rate is \$0.017 per metric ton-kilometer and the Armenian rate is \$0.024 per metric tonne-kilometer. The Georgian component of rail transport would be \$4.42 and the Armenian component would be \$8.64 for a total estimated freight cost of \$13.06 per tonne. No international taxes or custom fees are assumed within this estimate.

Since the calculated cost of purchasing coal from the Georgian Tkibuli mines is about \$30-\$35 and the rail freight cost is \$13, the cost FOB Hrazdan of \$43 to \$48 per tonne can be assumed. If we assume the lower figure of \$43 per tonne and the calorific value of 4,300 kcal/kg, we can calculate this coal, on a delivered energy basis at the plant, would cost \$10.00 per million kilocalories or \$2.44 per million BTU. This coal would be considered somewhat expensive due to the lower quality of coal involved, but represents a reasonable alternative (supplement) to the proposed Armenian sources.

5.3 Fuel Diversification

All of the natural gas that the Republic of Armenia currently receives comes from Russia through the North Caucasus region and the Republic of Georgia. However, fuel security issues are outside the scope of this project; the DECON (Germany)/ENEL (Italy) consortium under a TACIS program is currently investigating these issues, and several inquiries were made to identify other potential natural gas sources in the region.

5.3.1 Natural Gas From Iran

In 1995, during the fuel crisis in the Republic of Armenia, a Sales Agreement was signed between Iranian and Armenian gas counterparts that provides ground for gas deliveries from Iran. Currently this contract is treated as non-binding and one-sided by the Armenian side (a Gazprom and Gaz de France consortium). The following major articles are to be re-negotiated and discussed in the beginning of 2000:

- The price of gas at the Iran/Armenia border stipulated in the contract is \$84/tcm;
- The seasonal supply option is for 8 months only, excluding the period from November 21 – March 21;
- An operating pressure at Iran/Armenia border of 34 atm.

Armenian gas officials are to pursue the re-negotiation of the contract; these negotiations will target lower prices of gas at the border and a steady year-round supply at 55 atm of operational pressure. No commercial details are publicly available at this time on the negotiation progress.

Natural gas deliveries from Iran may become a useful fuel diversification tool for the Republic. However, this will be possible only in the case of a successful re-negotiation process and a stable political situation with respect to the natural gas currently supplied from Russia.

The estimation of the capital, O&M costs, and gas tariffs for this project are outside of the current study scope. Preliminary estimates, shown in the following table, are currently available from MoE and AGP for the Megri-Kajaran-Sisian-Jermuk-Ararat-Abovyan Option that seems to be the base routing being considered for Iranian gas delivery.

New Construction

Stretch	Length, km	Diameter, mm	System Capacity, mcm/day	Notes
Megri - Kajaran	40.0	700	1.0	Regional consumption only
Kajaran – Sisian	55.4	700	1.5	UGS injection possible
Angekhatot–Jermuk	42.3	700	3.5	UGS injection possible
Jermuk - Ararat	99.7	700	5.0	UGS injection possible
<i>Total</i>	<i>237.4</i>			

In addition to the new construction, 121.7 km of existing pipelines are to be rehabilitated.

The only estimate available for this analysis has a 1/1/96 base and reflects capital investment portions of \$82.0 and \$4.7 million for new construction and rehabilitation, respectively. The basis for these costs is considered to be “restricted” information and can not be verified. Specifically, it is unclear whether this capital cost includes EPC cost (materials and installation)

only, or if owner's costs are included as well. In the event that the above amounts include both EPC and Owner's costs, the proposed amounts are probably on the low side.

The same estimate provides the basis for the O&M expenditures that relate to the pipeline. The figure of \$6.24 million/year seems rather high. Similar projects in the CIS countries carry an average O&M cost of about one third that quoted in the estimate.

5.3.2 Natural Gas from Azerbaijan

Historically, Armenia has received Turkmenistan, Kazakhstan, Uzbekistan, and Iranian gas through the pipelines located at the Azerbaijan border. Since the beginning of the Azeri energy embargo that began in early 1990s, no gas delivery has taken place by that route. No potential for resumption of these deliveries is envisioned by Armenia until a settlement is reached on the Karabakh issue between Armenia and Azerbaijan.

Since the discovery of an estimated 800 billion cubic meters of gas at the Ashgheron Peninsula in Azerbaijan, some progress has been made to work out arrangements for the export of gas to Turkey and other neighboring countries. Preliminary mapping of the possible gas transmission lines has been worked out. These routings primarily include Azerbaijan – Georgia - Russia – Turkey, and bypass Armenian territory completely.

The Armenian side suggests that the most economic way of bringing Azerbaijan gas (and possibly other source gas) to Turkey is through the territory of Armenia. ArmRosGasProm has proposed to the European Community a feasibility study to evaluate this option. ILF Consultants and Engineers (Germany) was selected to start this work in February 2000. Based on the findings of this study, Armenia may be able to convince some interested parties to reformat the preliminary mapping to include Azerbaijan – Armenia – Turkey routing. Again, no positive resolution is expected until the dispute between Armenia and Azerbaijan is settled.

The Armenian side does not exclude the possibility of in-country consumption of Azerbaijan gas in addition to the transport option to Turkey. No details are available on this project at present. Preliminary estimates show that Apsheron gas can be available at the domestic Azeri market in about two years and on international markets in three to four years.

Based on discussions with MoE representatives, the Armenian part of the pipeline that is connected to Azerbaijan (20-25 km length) will have to be fully rehabilitated because of almost 10 years of non-operation in order to consider this option in the future.

5.3.3 Russian Gas for Cash Payments

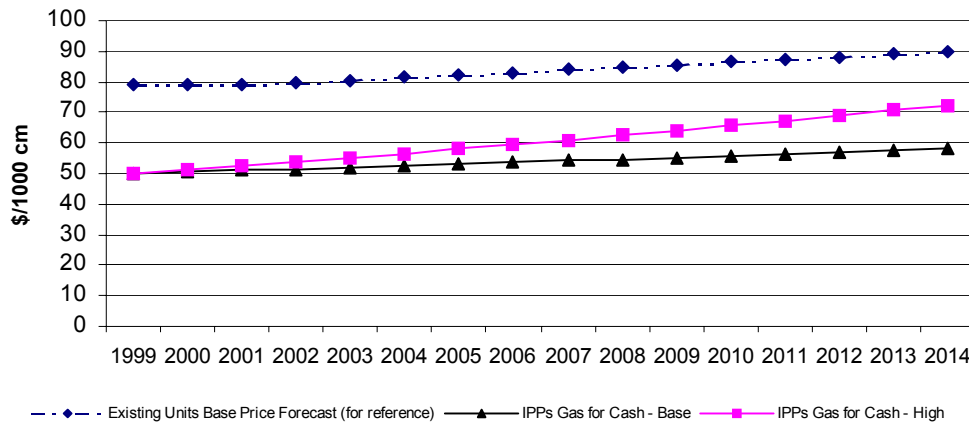
Currently, there is a substantial debt that existing power companies owe gas supplier (through Armenargo). After thorough investigation conducted in Georgia, it became clear that in case when payment arrangements for gas are arranged exclusively by currency (without any barter

and/or mutual accounting), the price of natural gas at the Armenia/Georgia border is about \$40 per 1000 cubic meters. The transportation within Armenian territory costs about \$10 per tcm. So, the price of natural gas at the Yerevan and/or Hrazdan sites will be about \$50 per tcm.

Full cash payments for gas are currently applicable only for any potential new gas-fired power plants. Most of these prospective power plants can be considered to operate as Independent Power Producers (IPPs). Thus, the payments for fuel are made in cash. Exhibit 11 below presents the natural gas IPPs option used in this study.

Exhibit 11

**Natural Gas Price Forecast
(IPP Gas Option)**



5.3.4 Coal From Georgia

One alternative (supplement) to the domestic coal is the Tkibuli coal mine located in Georgia as discussed in the prior chapter. This resource provides value because much investment has already been made in the mine and limited capital investment is required in order to re-establish acceptable production capability. Compared to the need to find and develop coal resources in Armenia, this is an attractive possibility. The capital injection required to locate coal reserves, conduct necessary analysis and feasibility studies, and construct a mine with the capacity of the Tkibuli mines in today's economy could easily range from \$100 to \$500 million. Smaller mine development in Armenia could easily range from \$30 to \$100 million. The Tkibuli mines require an investment in the neighborhood of \$20 million to revitalize production and they also have the potential of supporting at least a 150 MW power station with this level of capital infusion. This option appears to have the potential to support larger power stations and could possibly produce a higher quality coal if additional capital is invested.

If it is assumed that the Tkibuli mine produced coal for shipment to Armenia, as discussed in Chapter 5.2.3, the lower cost estimate of fuel has been projected to be at least \$43 per tonne, FOB power station at Hrazdan.

The comparatively high economic cost of a coal-fired power station is greatly dependent on the high capital investment required for the plant as well as the low calorific content of the coals found so far in this region.

At this point, Georgian coal can be assumed to be supplemental or to serve as an emergency coal supply to an Armenian CFB at the Hrazdan TPP site.

5.4 Conclusions

For the purpose of this LCGP, fossil fuel assumptions are proposed in Exhibit 12:

Exhibit 12 – Fossil Fuel Assumptions for LCGP

Case	Price (2000), \$/MMBtu	Price Escalation, %/year	Heating Value
Natural Gas (Existing Units)			
Base Price Forecast	2.16	1% starting 2004	7,900 kcal/m ³
High Price Forecast	2.16	2.5% starting 2004	7,900 kcal/m ³
Natural Gas (New IPPs – Cash Payment)			
Base Price Forecast	1.37	1%	7,900 kcal/m ³
High Price Forecast	1.37	2.5%	7,900 kcal/m ³
Natural and Synthesized Gas Mix² (80% NG + 20% SG)			
Base Price Forecast	1.72	1% starting 2004	6,795 kcal/ m ³
High Price Forecast	1.72	2.5% starting 2004	6,795 kcal/ m ³
Coal			
Local Coal - Base	1.48	0%	4,300 kcal/kg
Mix Coal ³ - High	1.96	0%	4,300 kcal/kg

² This blend fuel is used only at Yerevan TPP. The cost of synthesized gas is assumed to be zero. Mutual accounting is used for this purpose. About 20% of total gas volume consumed at Yerevan TPP is synthesized gas received from Nairit Factory.

³ Assumes 50%-50% blend of local and Georgian coal at the burner tip at Hrazdan TPP site.

References:

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- [3] Quantitative Assessment of Trends in Armenia Energy Sector up to Year 2010, ERC, 1999
- [4] The Nor Arevik Coal Deposit, Southern Armenia, Draft Report, USGS, 1999
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- [6] Armenia: Power Supply/Conservation Program, CFB Unit at Hrazdan TPP, Feasibility Study, Burns and Roe, 1998